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EXHIBIT "1"

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Energy in Action

IRP Guidelines

Purpose

The purpose of this document is to outline the process, as proposed by the Integrated Resource Plan (IRP) Subcommittee, that utilities would use when developing and filing their IRP.

These guidelines are intended to support SC Code of Laws 58-37-40(c), which states, "The State Energy Office, to the extent practicable, shall evaluate and comment on external environmental and economic consequences of each integrated resource plan submitted and on the environmental and economic consequences for suppliers and distributors."

Although the IRP development process incorporates utility energy efficiency programs, renewable energy plans, and fuel costs – for investor owned utilities (IOUs) specifically – they are evaluated by the Public Service Commission (Commission) under separate dockets. The IRP is for planning purposes; other dockets are for cost recovery.

Background

The IRP Subcommittee was developed in response to the Energy Plan IRP recommendation. The recommendation is as follows:

Integrated Resource Planning Process

Challenge: Ensure that electric utility IRPs clearly demonstrate and reflect access to energy supplies at the lowest practical environmental and economic cost and that demand-side options are pursued wherever economically and environmentally practical.

Background: Electric utility IRPs vary. A robust analysis is important to accurately demonstrate the lowest practical environmental and economic cost for consumers statewide. This analysis should consider economic and environmental metrics; a minimum set of alternative resource portfolios; a minimum set of alternative scenarios for analysis; joint dispatch of generating resources; and coordinating the construction of new electricity generation.

Approach: The Energy Office should establish a committee to study matters related to the IRP process including the costs and benefits that can be achieved by changes to the IRP process. The study committee should consist of representatives from investor-owned utilities, Santee Cooper, the electric cooperatives, conservationists, and other interested stakeholders.

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IRP Statute

SECTION 58-37-40. Integrated resource plans.

(A) Electrical utilities and the South Carolina Public Service Authority must prepare integrated resource plans. The South Carolina Public Service Authority and electrical utilities regulated by the Public Service Commission must submit their plans to the State Energy Office. The plan submitted by the South Carolina Public Service Authority must be developed in consultation with electric cooperatives and municipally-owned electric utilities purchasing power and energy from the authority and must include the effect of demand-side management activities of electric cooperatives and municipally-owned electric utilities which directly purchase power and energy from the authority or sell power and energy which the authority generates. All plans must be submitted every three years and must be updated on an annual basis. The first integrated resource plan of the South Carolina Public Service Authority must be submitted no later than June 30, 1993. An integrated resource plan may be patterned after the integrated resource planning process developed by the Public Service Commission. For electrical utilities subject to the jurisdiction of the commission, submission of their plans as required by the commission constitutes compliance with this section. Nothing in this subsection may be construed as requiring interstate natural gas companies whose rates and services are regulated only by the federal government or gas utilities subject to the jurisdiction of the South Carolina Public Service Commission to prepare and submit an integrated resource plan.

(B) Electric cooperatives and municipally-owned electric utilities must submit integrated resource plans to the State Energy Office whenever they are required by federal law to prepare these plans or if they plan to acquire, by purchase or construction, ownership of additional generating capacity greater than twelve megawatts per unit. An integrated resource plan must be submitted to the State Energy Office by an electric cooperative or municipally-owned electric utility twelve months before the acquisition, by purchase or construction, of additional generating capacity in excess of twelve megawatts per unit. For an electric cooperative, submission to the State Energy Office of its plan in a format complying with the then current Rural Electrification Administration regulations constitutes compliance with this section.

(C) The State Energy Office, to the extent practicable, shall evaluate and comment on external environmental and economic consequences of each integrated resource plan submitted and on the environmental and economic consequences for suppliers and distributors.

(D) The State Energy Office shall coordinate the preparation of an integrated resource plan for the State and shall coordinate with regional groups, including the Southern States Energy Board.

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(E) The State Energy Office must not exercise any regulatory authority with regard to the requirements set forth in this chapter.

Timeframe

The IOUs must file a 15-year IRP every three years with the Commission, and must file a short-term action plan (STAP) with the Commission in each of the intervening two years between the filing of the detailed 15-year plans. The South Carolina Public Service Authority (Santee Cooper) must file its 15-year IRP every three years and a STAP in each of the intervening two years with the State Energy Office.

Public Participation

The IOUs and Santee Cooper must each hold at least one public engagement sessions which provides utilities an opportunity to share and discuss changes to their IRPs with interested parties every three years as part of the IRP process. The utilities will consider the public input from these meetings during the development of the IRP. At least 30 days prior to holding an engagement session, each utility must notify the public through methods such as news publications, bill inserts, customer email lists, and social media information about the location and time of said engagement session. This notification must include a summary of anticipated changes (including, but not limited to: description of its proposed planning and modeling methodology, its model inputs, its draft resource portfolios, and its draft scenarios and/or sensitivities). An ORS representative must attend each public engagement session. Each utility required to submit an IRP must include with its submission a summary of the engagement session including comments received and appropriate responses.

Best Practices

Through a collaborative process including the SC Energy Office, conservationists, utilities and other interested parties, the following IRP best practices were developed.

Statement of purpose: The purpose of the best practices is to provide guidelines for the preparation of an IRP in order to encourage comparability and consistency among electric utilities.

Definitions:

- Best Practices – A process that promotes the most cost effective and energy efficient methods, considering uncertainties, to encourage their adoption and use by South Carolina utilities.

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- Demand-side management (DSM) – DSM encompasses all energy efficiency measures and all demand response measures
- Integrated Resource Plan – A utility's resource plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. It is developed and planned based on the available information and situation at one point in time.
- Resource portfolio – a year-by-year schedule of system additions and retirements chosen by utility management, encompassing traditional generation units, DSM programs and renewable energy resources.
- Scenario – a collection of assumptions about future circumstances that utility management does not control, such as fuel prices, gross load obligations, technology costs, policy and regulations.
- Sensitivity – variation of an isolated assumption while holding all other assumptions constant, in order to understand the importance of the assumption of interest to the results.

Best Practices:

1. Each utility should analyze multiple resource portfolios that consider a range of supply-side and demand-side resources including DSM and renewable energy (RE) resource options. A modeling process should incorporate cost-effective DSM and RE options available to meet both capacity and energy needs and reflects a utility's most recent DSM suite of programs.

2. The IRP analysis should include, at minimum, alternative DSM and RE portfolios of at least one high and one low DSM and at least one high and one low RE portfolio and should contain a diverse mix of DSM and RE measures, and the associated cost assumptions used for each of the portfolios. The measures and portfolios included may be generic in nature and utilities would not necessarily make any representation that they are attainable or meet cost effectiveness tests.

3. Each utility should expand its evaluation to establish a set of scenarios and/or sensitivities to analyze the robustness of each resource portfolio. The scenarios and/or sensitivities should reasonably capture the range of key variables affecting the utility's plan. The IRP should describe each scenario and/or sensitivity. Scenarios and/or sensitivities should explore uncertainties in fuel prices and load growth. As

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appropriate, other uncertainties such as carbon and technology costs should also be explored.[1]

4. The IRP must list the expected retirement date for each unit planned to retire within the 15-year IRP analysis period, and describe any substantial conditions on which the retirement date depends. The IRP must also list the license expiration date for each unit as appropriate. If a unit does not have an expected retirement date, the IRP must provide a supporting explanation.

5. The IRP must present appropriate economic and environmental metrics for all portfolios across all scenarios and/or sensitivities and confirm that each portfolio is compliant with all local, state and federal environmental laws and regulations.

    a. Economic outcome metrics at minimum must include the present value of the system incremental revenue requirements. These metrics should also show the absolute difference and percentage difference in the economic costs of the various portfolios as compared to the base case.
    b. Environmental outcome metrics at minimum must include air emissions. Other environmental outcome metrics such as water withdrawals, water consumption, and coal ash production should be evaluated as appropriate. These metrics should also show the absolute difference and percentage difference in the environmental outcomes of the various portfolios as compared to the base case.

6. The IRP must select one plan which the utility offers as a reasonable way to meet system load requirements, and must discuss that choice based on relevant economic and regulatory factors, as well as any substantial regulatory or market assumptions that also influence the selection.

7. The IRP must provide the following analysis input assumptions for each year of the analysis including for all years beyond the 15-year planning period. These assumptions must be provided for each scenario and/or sensitivity, with a description of which assumptions were varied within each scenario and/or sensitivity. Each utility

[1] Each resource portfolio should be analyzed across all scenarios and/or sensitivities, and scenarios and/or sensitivities should be kept consistent for each resource portfolio. For example, a utility develops Resource Portfolios A, B, and C, and scenarios and/or sensitivities X, Y, and Z. The utility should model Resource Portfolio A under each scenario and/or sensitivity – scenarios and/or sensitivities X, Y, and Z – and also should model Resource Portfolios B and C under each of the same scenarios and/or sensitivities – scenarios and/or sensitivities X, Y, and Z. Thus the scenario and/or sensitivity assumptions are kept constant when evaluating each resource portfolio, so that the modeling results for the different resource portfolios can be meaningfully compared. Finally, only portfolios and scenarios and/or sensitivities that serve the same gross load obligation before DSM can be meaningfully compared within an IRP

must use reasonable assumptions. Data sources must be indicated and forecast methodologies must be described.

a. System sales
b. System summer and winter peak demand
c. Delivered fuel prices
d. Emissions price (e.g. CO_2)
e. Technology costs for each technology modeled
f. Price of purchased power alternatives including economy purchases (energy and capacity, QF and non-QF)

8. The IRP must separately identify the expected energy and capacity impacts of DSM programs and of customer-owned distributed generation. This only refers to assumed future DSM and distributed generation impacts.

9. The IRP must identify the amount of existing purchased capacity reflected in the resource plan, including where possible resource type, energy and demand contributions, and contract duration.

10. The IRP should indicate data sources and describe analytical methodologies used to derive any major assumptions not otherwise addressed, such as reserve margin requirements, resource integration needs and costs, and resource dependable peak capacity assumptions.

11. The IRP must provide a brief overview of any major trends, uncertainties, challenges, or new technologies that are likely to impact the utility and its customers that are not otherwise described.

12. The IRP must include a list and description of existing and potential DSM programs.

13. For informational purposes only, each utility should include in its IRP, or in an appendix to the IRP, a reference to the resource portfolio, the scenario and/or sensitivity, and the unit retirement assumptions that will be used to derive the utility's avoided costs that are used in DSM program evaluation, QF power purchase rates, and any other tariffs that apply avoided cost concepts. This data is expected to reflect information already provided from items #1-12, and the utility may caveat its response by noting that actual avoided cost inputs can be subject to change due to updated price forecasts and/or other new information including by not limited to Commission directives in other dockets.

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Filing

The IOUs will file their IRP with the Commission. Upon annual filing and the establishment of an IRP docket, interested parties may intervene and comment. The utilities are encouraged to respond to intervenors and public comments. A common question/theme can have one response. If necessary, the parties may jointly request that the Commission hold a hearing. The utilities, through their IRPs will:

1) Publicly report to the Commission the substance of the discussion at public engagement sessions, including public feedback, recommendations, and comments;

2) Include responses to intervenors and comments.

After considering the IRP, public comments, intervenor comments, and utility responses, the committee respectfully requests the Commission consider filing an order accepting, denying, or modifying the methodology, model inputs, range of resource portfolios, and range of scenarios and/or sensitivities contained in the IRP. The Commission may also consider recommending that further methods, inputs, portfolios, scenarios, or sensitivities be explored. Additionally, the Commission may also consider directing the utility to respond to intervenors and comments where the response is inadequate. Approval of methods, inputs, portfolios, scenarios, and sensitivities does not constitute approval of the IRP as a whole.

Per SC Code of Laws 58-37-40, Santee Cooper will submit its IRP to the State Energy Office, which may request additional information concerning comments where the response is inadequate.

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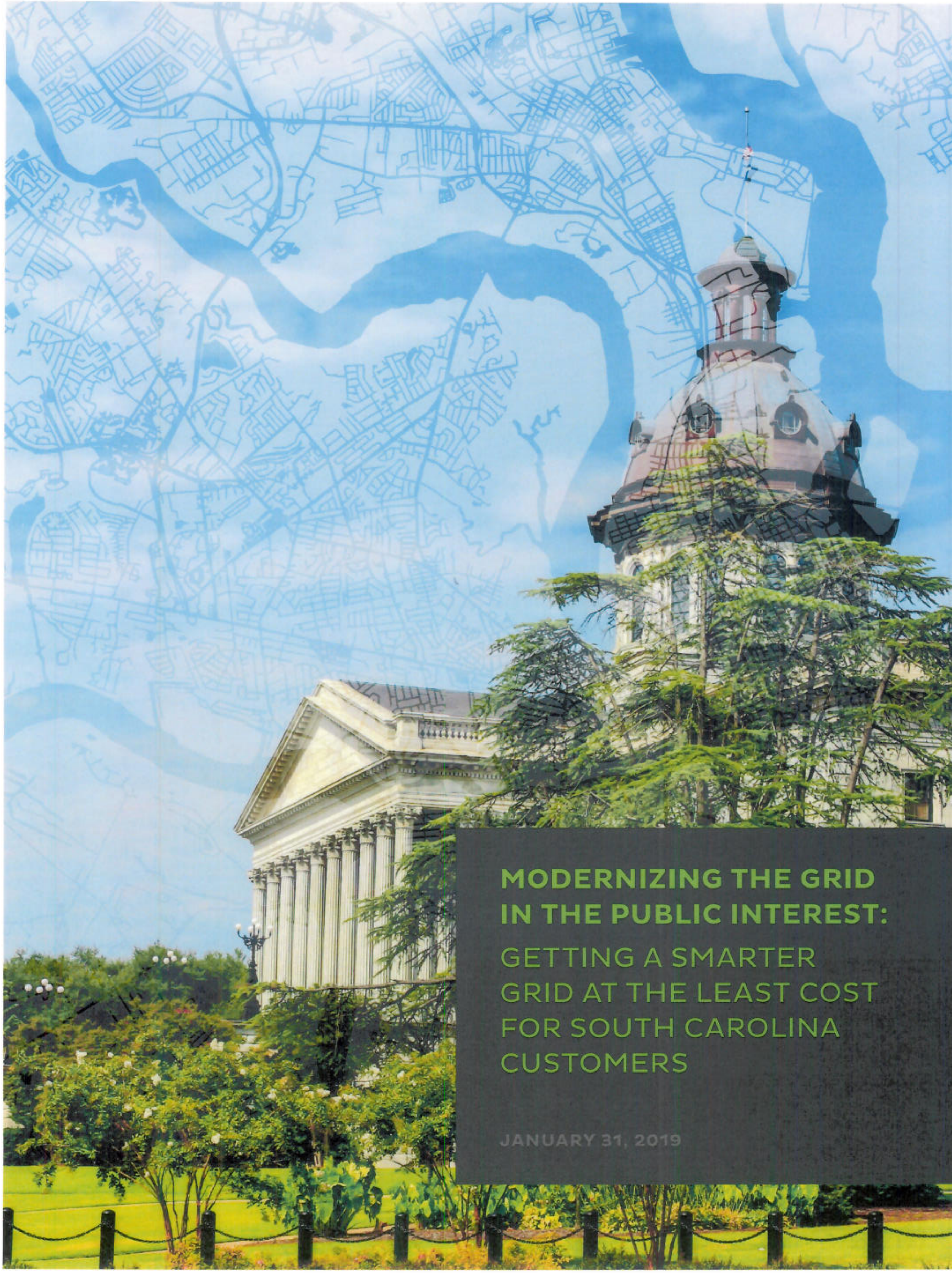

MODERNIZING THE GRID IN THE PUBLIC INTEREST:

GETTING A SMARTER GRID AT THE LEAST COST FOR SOUTH CAROLINA CUSTOMERS

JANUARY 31, 2019

ABOUT GRIDLAB

GridLab is a non-profit organization that provides comprehensive and credible technical expertise on the design, operation, and attributes of a flexible and dynamic grid to assist policy makers, advocates, and other energy decision makers to formulate and implement an effective energy transformation roadmap. GridLab offers technical expertise, training, and a connectivity platform for sharing information about the rapidly-evolving electric distribution grid landscape.

ABOUT THE AUTHORS

Paul Alvarez is the President of the Wired Group, the leading grid modernization consultancy for US consumer and environmental advocates. A recognized expert in cost-effective grid modernization, he has testified on grid modernization plans, investments, and performance before state regulators from California to Massachusetts. Paul led two of only three post-deployment, objective evaluations of grid modernization programs ever completed (SmartGridCity™ in Boulder, Colorado and Duke Energy in Cincinnati, Ohio).

Dennis Stephens is the Senior Technical Consultant for the Wired Group. He has 35 years' experience in grid operations, planning, and development for Xcel Energy, including service areas with high penetrations of distributed energy resources. Dennis held corporate roles in grid modernization and asset management for Xcel Energy, and played a leadership role in the Boulder, Colorado SmartGridCity demonstration project. A team Dennis led won a National Edison Award for Utility Innovation in 2006.

Mr. Ric O'Connell, Executive Director, GridLab, also contributed to this paper.

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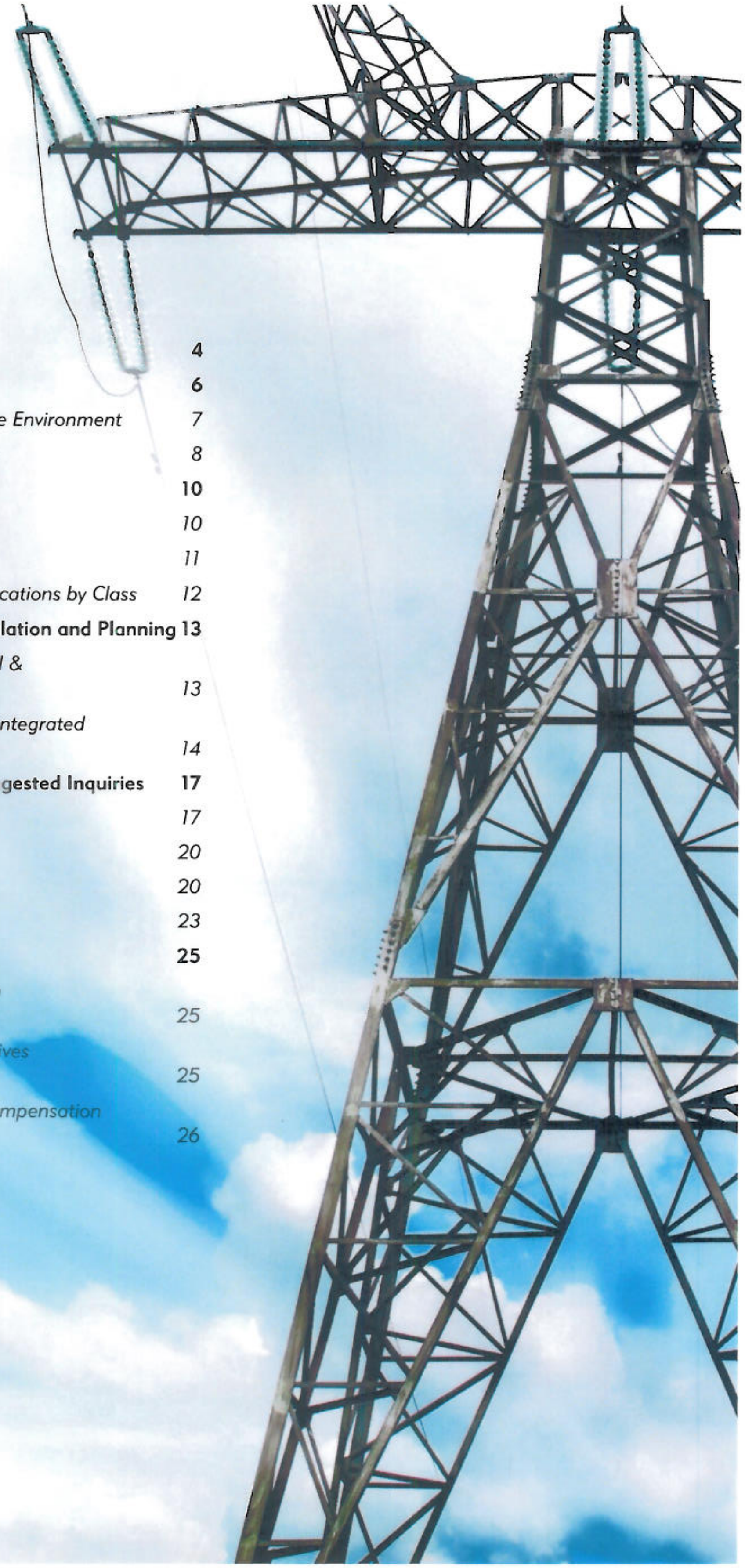

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1 EXECUTIVE SUMMARY

Utilities across the world are taking steps to modernize their electric grids. In the most basic sense, this means augmenting the grid with software and communications technologies to help the grid meet the new demands society is placing upon it. States serious about grid modernization are taking a thoughtful and methodical approach through dedicated investigational proceedings – a reflection of the capital expenditures about to be made, as well as the consequences of mistakes.

Grid modernization offers many potential benefits if designed and executed well. If economic benefits are maximized, a distribution grid can be made smarter at low cost to customers. There is wide variation in grid modernization benefits delivered by utilities, and a dearth of objective research into quantifiable outcomes. Investor-owned utilities (IOUs) are motivated to spend more capital than necessary on grid modernization, and may invest in capabilities with limited benefits for customers. It is difficult for utilities to maximize many types of available economic benefits for customers, due to either economic penalties for doing so (the throughput incentive, see Section 3), or simply to challenging organizational and business process change requirements. This paper is designed to help South Carolina stakeholders understand how the grid can be modernized such that direct economic benefits to customers can exceed its rate impacts. The paper is essentially a "how to" guide to a favorable benefit-to-cost ratio for customers.

The paper begins with a discussion of the potential benefits of grid modernization, including indirect benefits to communities and the environment as well as direct economic benefits to customers. The paper continues by examining the challenges to securing a favorable customer benefit-to-cost ratio from grid modernization, focusing on the unintended

consequences of cost-of-service regulation. Examples from other states illustrate how capital bias, the throughput incentive, and typical grid modernization cost recovery make it virtually impossible to get a smarter grid without dramatic, permanent increases in stakeholder engagement in grid planning and performance.

The next part of the paper describes what regulators in other states are doing to expand stakeholders' roles in grid planning, as well as emerging best practices in transparent grid planning GridLab has observed in development in other states. The paper concludes with a look at the South Carolina Grid Improvement Plan Duke Energy recently filed, helping stakeholders focus their attention on admirable characteristics, significant challenges, and critical omissions.

This paper is not meant to discourage grid investment. Rather, this paper intends to stimulate stakeholder interest, engagement, and expertise required for cost-effective grid investment, both before and after those investments are made. The paper recognizes that grid investment is not a one-time event; it is instead a long-term process which requires new roles for, and demands greater commitments and expertise from, regulators and all stakeholders. In the long term, fundamental changes to utility capital bias and the throughput incentive may be required. But today, sound grid planning and carefully considered utility investments, combined with extensive post-deployment efforts and performance measurement, can fill the gap and help South Carolina customers get the modern grid they deserve at a cost that does not adversely impact South Carolina's economy.

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2 GRID MODERNIZATION POTENTIAL

US IOUs have dramatically increased distribution investment in recent years. Since 2010, distribution plant in service balances have grown at a rate four times faster than the US consumer price index. The typical objectives given by utilities for grid modernization is to reduce operations and maintenance (O&M) spending and increase reliability. Yet despite this growth, grid investments do not appear to have improved reliability or reduced O&M spending, as shown by the two figures below.

The most common reliability metric is SAIDI, or System Average Interruption Duration Index, which was developed by the IEEE. Higher reliability would be reflected by lower (shorter) SAIDI metrics. Other standard reliability measurements referred to in this paper include SAIFI, or System Average Interruption Frequency Index, and MAIFI, or Momentary Average Interruption Frequency Index. All utility performance charts in this paper are provided courtesy of the Utility Evaluator™.

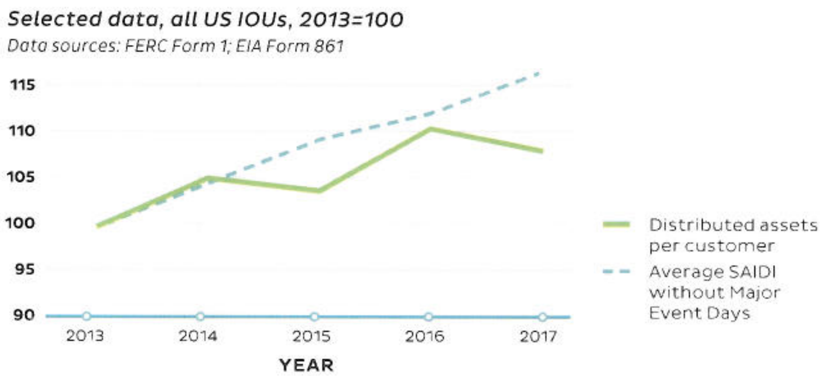

FIGURE 1. *Despite increases in recent grid investment, reliability (as indicated by increasing SAIDI) is deteriorating.*

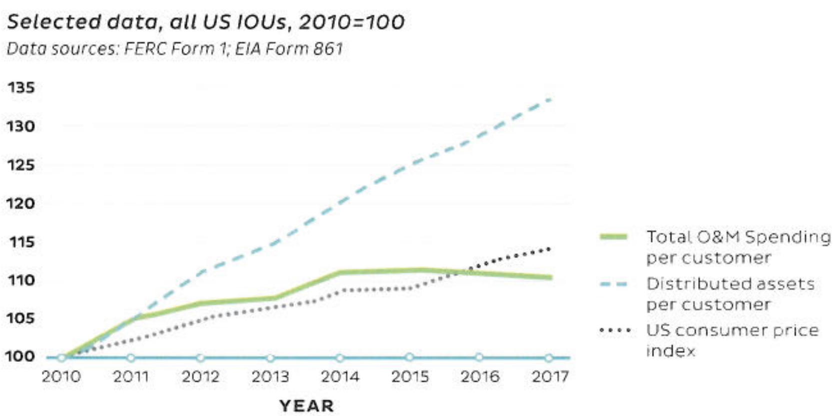

FIGURE 2. *Distribution grid investments are not reducing O&M spending as expected.*

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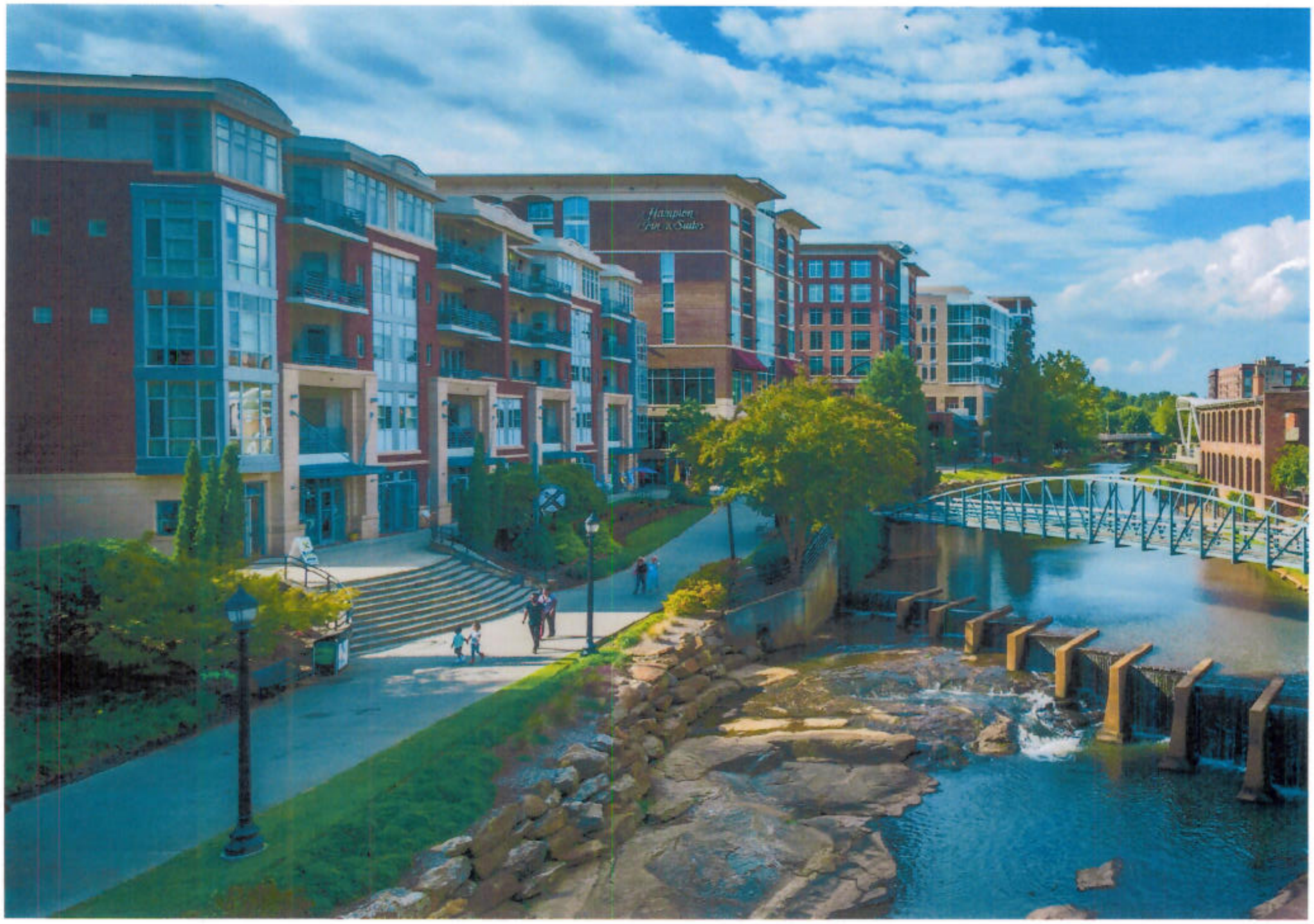

As described below, the potential benefits of grid modernization, including both indirect benefits for communities and the environment, as well as direct economic benefits for customers, are significant. In fact, GridLab believes direct economic benefits alone are potentially great enough to enable South Carolina customers to achieve a smarter grid in which the economic benefits exceed rate increases related to grid investment. Section 3 describes why that potential goes unrealized in most cases, and Sections 4 and 5 describe what South Carolina regulators and stakeholders can do about it.

2A. INDIRECT BENEFITS TO COMMUNITIES AND THE ENVIRONMENT

Appropriate grid investment – that is, investment in capabilities delivering customer benefits greater than costs – offers many indirect benefits to communities and the environment. The largest of these potential indirect benefits are described below, along with the risks associated with each.

Promotes Economic Development

- Low electric rates, achieved through cost-effective grid investment and high grid asset utilization (distributing more electricity with fewer assets), spurs commercial and industrial activity and creates jobs.
- Distributed energy resources (DER, such as rooftop solar and storage)[1] are already cost effective in many instances and create jobs (the solar energy industry alone employed 260,000 Americans in 2016).[2]
- Risks: Cost-ineffective grid investments, or failure to maximize the benefits from grid investments, will result in high electric rates, discouraging economic growth.

Improves Reliability and Resilience

- Some of the same investments designed to increase grid DER capacity and asset utilization also improve grid reliability and resilience, which in turn promotes economic development.
- Risks: Some grid investments proposed as reliability and resilience improvements (undergrounding,

hardening) offer low (or in some cases no) benefits per dollar, resulting in higher electric rates with little or no improvement in reliability or resilience.

Accommodates Customer DER and Electrification Choices

- As costs fall, more and more customers become interested in owning DER and electric vehicles (EV).
- Appropriate investments can technically prepare grids for high levels of DER and EV, thereby avoiding limitations on customer choice.
- Risks: Investments made to a greater geographic extent than necessary, or earlier than necessary, will result in unnecessarily high electric rates.

Encourages Energy Capitalism and Democracy

- "Prosumers" (early adopters of DER) are getting more sophisticated. Some are interested in being compensated for services they could offer to the utility and to other customers.
- In some cases, these alternative providers may be able to deliver services more cheaply than a utility, or to help avoid a utility investment (such as a substation or circuit capacity upgrade).
- Secure access to energy usage data leads to more informed energy consumers, who should have a choice in energy management services providers. The Connect-My-Data standard[3] enables customers to authorize third parties to access usage data from their utility on an ongoing or one-time basis. See text box for more information on Connect-My-Data.

GREEN BUTTON Connect My Data

The Connect-My-Data (CMD) standard was developed by the non-profit Green Button Alliance, an industry-led organization originally established in response to a call to action from the White House in 2012. While perhaps best known for Green Button Connect — a standard downloading approach to historical customer usage data requests — the Green Button standard with the greatest potential for energy conservation and competitive management services markets is CMD. CMD is an open-data standard designed to unlock access to utility interval usage and billing data, providing easy, seamless, ongoing access for software applications like smart-phone apps. Green Button CMD enables utility customers to authorize third-party solutions to quickly and securely obtain interval meter data and enables an accurate and detailed level of analysis to inform energy and water management decision-making, while ensuring customer data are protected and their privacy is maintained.

Reduces Environmental Impact

- South Carolina law enables IOUs to recover costs from customers associated with securing up to 2% of electricity needs from renewable generation sources. In some cases, customer investments in DER like PV Solar can cost-effectively avoid utility grid investment.
- In addition, IOUs in South Carolina are authorized to earn incentives upon the achievement of energy efficiency goals. In some cases, utility investments (like Integrated Volt-VAR Control, see Section 4) can achieve conservation at lower cost than customer investments.
- A more energy-efficient grid, or a grid capable of accommodating greater levels of renewable DER, can therefore reduce the cost to comply with environmental goals.
- Risks: If IOUs spend more than necessary to improve grid efficiency or accommodate DER, environmental concerns may be inaccurately associated with high costs.

2B. DIRECT ECONOMIC BENEFITS FOR CUSTOMERS

In addition to indirect benefits to communities and the environment, grid modernization offers potential direct economic benefits for customers. If maximized, these direct economic benefits can fully offset the cost of grid modernization.

Reductions in Operating Expenses

- Smart meters' remote meter reading and service disconnect/reconnect features can reduce the labor costs of the metering function.
- Smart meters facilitate prepayment programs, which reduce bad debt expense and improve the satisfaction of customers who prefer to prepay.

Improvements in Revenue Assurance

- Analyses of interval usage data (every 15 minutes) available from smart meters can detect meter bypass, a type of electricity theft which all customers pay for through higher rates.
- Smart meters are more accurate than analog meters, which more often run slow than fast. All customers pay for electricity consumed but not billed due to slow analog meters.
- Analyses of data from smart meters installed for 3-phase (commercial) customers can detect meter

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billing errors (such as consumption missing from one of the phases).

- Remote meter disconnect eliminates unbilled electricity use in vacant premises.

Increased Conservation

- Conservation Voltage Reduction, a capability of Integrated Volt-VAR Control (IVVC), is one of the most cost-effective means available to reduce the amount of electricity customers use.
- Smart meters' read frequency (generally daily) permits utilities to offer high bill alerts (a text or e-mail notification that a customer's in-month usage is likely to result in a bill higher than that customer's pre-set target). Such programs may reduce customer usage, as can improved usage data access through compliance with the aforementioned Connect-My-Data standard.
- Customer programs, such as time-varying rates, are associated with reductions in electricity use. Correct implementation of customer programs are key to successful outcomes, and policy papers from national consumer advocate groups can help guide satisfactory program implementation.[4]

Reductions in Peak Demand

Smart meters track both how much electricity a customer uses as well as when a customer uses it. This capability is ideal for time-varying rates. Research indicates that certain types of time-varying rates modify when customers use electricity.[5] Changing usage timing through price signals reduces the need for new generation or other investments for which customers must pay. Time-based price signals can also help accommodate high levels of intermittent renewable generation at a lower cost than would otherwise be possible. Research also indicates that time-varying rates help reduce overall electricity use in addition to helping reduce electric use during peak demand periods.[6]

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3 GRID MODERNIZATION CHALLENGES

While the potential direct and indirect benefits of grid modernization are great, there are significant challenges to securing customer benefits in excess of rate impacts. The unintended consequences of cost-of-service ratemaking, including capital bias, the throughput incentive, and certain types of cost recovery practices, are the sources of these challenges.

3A. CAPITAL BIAS

Investor-owned utilities in the US have been encouraged to invest capital in their grids since the development of the cost-of-service model in the early 20th century. This arrangement, which involves paying utilities a profit margin on invested capital, has worked well for shareholders, communities, and customers for about 100 years. Investments to expand the grid's reach and capacity were needed to accommodate economic development, and the investments and associated utility profits were easily paid off through growing volumes of electricity sales.

However, electricity sales are no longer growing, and the relationship between economic development and electricity sales no longer holds. For example, despite South Carolina's booming economy, Duke Energy Progress plus Duke Energy Carolinas' South Carolina electric sales volumes over the past 8 years are essentially flat (see Figure 3 below courtesy of the Utility Evaluator). Duke Energy's experience in South Carolina mirrors that of utilities nationwide, for which electricity use and peak demand have fallen 5.4% and 8.7% since 2010, respectively,[7] despite growing US Gross Domestic Product.

DUKE ENERGY GWH DISTRIBUTED IN SOUTH CAROLINA

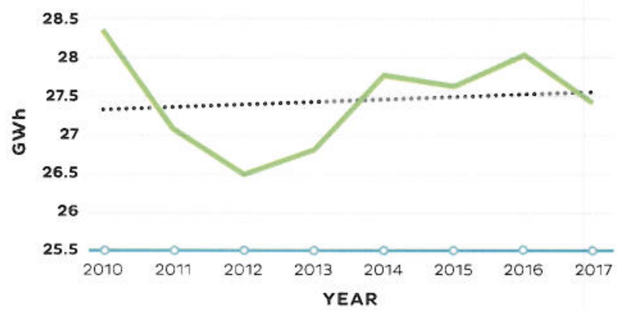

FIGURE 3. ***Duke Energy Sales (GWh) in South Carolina***
Data sources: EIA Form 861

Grid investments can no longer be repaid simply through sales volume increases. Rate hikes will instead be needed to repay grid investments, making stakeholder scrutiny over how much utilities invest, on what capabilities, and to what end results, much more important than such scrutiny has been in the past. To add to the difficulty, stakeholders do not have the resources or expertise to challenge the technical arguments utilities use to justify grid investments. Recent experience shows that some US IOUs propose more grid investment than may be necessary or cost-effective. In 2018, regulators in Kentucky,[8] Massachusetts,[9] and New Mexico[10] rejected smart meter proposals, while regulators in North Carolina denied favorable cost recovery for Duke Energy's Power Forward proposal, referring the utility to existing proceedings for stakeholder engagement.[11] So far in 2019, the Virginia SCC denied most of Dominion's multi-billion dollar grid transformation plan, suggesting the utility resubmit "a sound and well-crafted Plan."[12]

There are many examples of capital bias in IOU grid modernization proposals. In California, Pacific Gas & Electric and Southern California Edison exaggerated the reliability risks posed by DER to justify billions of dollars in grid investments.[13] In Ohio, First Energy has proposed over $500 million in grid investments for improved reliability despite above average and even top-quartile reliability performance.[14] In Virginia, Dominion Energy is attempting to reserve most DER investments for itself.[15] In addition, all IOUs refuse to examine the benefit-cost-risk profiles of new "internet of things" communications networks available from third party providers, preferring capital investment in proprietary meter communications networks.

The analogies to power plant investments, with which South Carolina stakeholders are unfortunately all too familiar, are clear. For decades, US utilities invested in generation capacity in the name of reliability. Regulators and stakeholders, over-matched in resources and expertise, eventually turned to Integrated Resource Planning to help level the playing field. Transparent, integrated distribution planning (IDP) processes can help stakeholders do the same in distribution. Emerging best practices in IDP processes will be discussed in Section 4B.

3B. THE THROUGHPUT INCENTIVE

While the immediately preceding section on capital bias describes why IOUs might invest more in their grids than necessary, this section describes the throughput incentive, and how it discourages utilities from maximizing the energy conservation opportunities available from grid investments. The throughput incentive is simply short-hand for the economic benefits an IOU gains from distributing more energy than anticipated in its most recently-completed rate case. The term also incorporates the economic harm done to an IOU when it distributes less energy than anticipated. In short, any actions customers take to reduce electricity purchases reduce utilities' opportunities to earn authorized rates of return. The throughput incentive is an unintended consequence of traditional utility ratemaking, and is illustrated through a highly simplified example.

Utility rates are established on the basis of costs and anticipated sales volumes. Assume a utility needs to collect $1 billion from customers in a year to cover costs and authorized profits. Assume the utility expects to sell 20 billion kWh per year. By dividing $1 billion by 20 billion kWh, one can see that the utility must charge $0.05 cents per kWh to collect $1 billion. It is easy to see that if the utility only sells 19 billion kWh in a year, the utility will not get the $1 billion it needs to cover costs and authorized profits; it is also easy to see that if the utility sells 21 billion kWh in a year, it will get more than the $1 billion it needs, leading to greater profits than authorized. This, in a nutshell, is the throughput incentive, and explains why utilities always want to sell more electricity.

In most grid modernization deployments, energy conservation and reductions in peak demand represent the largest potential sources of direct economic benefits to customers.[16] As described in Section 2B., time-varying rates and Connect-My-Data standard compliance associated with smart meters can reduce electric use. This explains why utilities with smart meters fail to promote time-varying rates to customers. Though the Edison Electric Institute estimates that 60% of US households have smart meters,[17] only 3% are billed on time-varying rates.[18] It also explains why utilities resist Connect-My-Data standard compliance; regulators in California, Colorado, Illinois, New York, and Texas have mandated IOU compliance. Similarly, IOUs tout the conservation voltage reduction benefits of IVVC when proposing IVVC investments. Yet due to the throughput incentive, most utilities (including Duke Energy in North Carolina)[19] only employ conservation voltage reduction a few dozen hours every year, during periods of peak demand.

In addition, IOUs justify some grid modernization investments as preparation for approaching increases in DER capacity. GridLab encourages stakeholders to examine these needs closely, as experience in California and Hawaii indicates that reliability-related challenges from DER only occur on circuits with very high DER capacity relative to loads. But while utilities promote grid investments to accommodate more DER capacity, the throughput incentive simultaneously prompts them to discourage DER deployment through a variety of means. Utilities routinely discourage DER deployment by pursuing onerous net metering terms and demanding interconnection capabilities (many of which utilities fail to use); by opposing customer-sited carve-outs in state renewable portfolio standards; by opposing solar system leases; and by employing slow interconnection application review and approval processes.

To summarize, as a result of the throughput incentive, utilities are inclined to discourage the very conservation benefits customers need to reduce, or even completely offset, the cost of grid modernization. Post-deployment performance measurement is therefore an essential component of grid modernization and is discussed in Sections 4, 5, and 6.

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3C. METHODS OF COST RECOVERY AND COST ALLOCATIONS BY CLASS

Finally, common methods of cost recovery and cost allocations by customer class figure large in stakeholders' attempts to secure a favorable benefit-to-cost ratio for customers. Utilities commonly pursue grid modernization cost recovery outside of rate cases, for example through bill riders. Utilities like bill riders, as they eliminate cost recovery delays and maximize the likelihood the utility will earn its authorized rate of return on capital invested. Unfortunately, recovering grid modernization costs outside of rate cases is a bad deal for customers. This is because unless and until operating cost reductions and revenue assurance improvements (both associated with smart meters) are reflected in the utility's accounting records in a rate case test year, these direct economic benefits will not result in rate reductions.

Without the need to hold a rate case to recover grid modernization costs, utilities can deliver these direct economic benefits to shareholders, and withhold them for customers, for years. Even without a rider, adept rate case timing can deliver the same result. "Rate case timing" occurs when a utility selects a test year before implementing smart meter-related operating cost reductions and revenue assurance improvements. Implementation occurs after the rate case, such that the direct economic benefits accrue to shareholders until a subsequent rate case recognizes the benefits in some subsequent test year's books, which could be many years away. These tactics can effectively deny these direct economic benefits from reaching customers. Regulators in Oklahoma[20] and Ohio[21] have predetermined annual rider revenue requirement reductions based on utilities' smart meter-related benefit forecasts to address this issue.

Another cost recovery issue impacting the customer benefit-to-cost ratio concerns grid modernization cost allocations by customer class. Traditional cost allocation methods spread distribution costs equally between rate classes, with residential customers paying their fair share of distribution costs utilities incur. However, most grid modernization spending is oriented to extraordinary improvements in reliability, beyond what might be required under a "routine course of business" scenario. According to the best research on the value of electric service interruptions, the economic benefits of reliability improvements accrue almost entirely to commercial and industrial customers.[22] The takeaways are 1) a favorable benefit-to-cost ratio for residential customers relies almost entirely on maximizing smart meter and conservation voltage reduction benefits; and 2) traditional methods for allocating distribution costs should not be used for grid investments designed primarily to improve reliability.

Concluding Thoughts on Grid Modernization Challenges

In its presentation at Duke Energy's Grid Improvement Workshop, Rocky Mountain Institute reported that the distribution and transmission component of US IOU customers' bills increased 63% from 2006 to 2016.[23] While completely offset by reductions in electricity generation costs, further reductions in electricity generation costs are unlikely. The implication is that utilities, regulators, and stakeholders must spend more time and effort controlling distribution grid spending and maximizing the direct and indirect benefits of such spending. After a decade of focus on generation, it is appropriate for South Carolina stakeholders to allocate more time and attention to the distribution grid.

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4 GRID MODERNIZATION: BEST PRACTICES IN REGULATION AND PLANNING

This section of the paper describes what state utility regulators are doing to manage ever-larger grid modernization proposals from IOUs, and outlines recommended features of an integrated distribution planning process reminiscent of integrated resource planning.

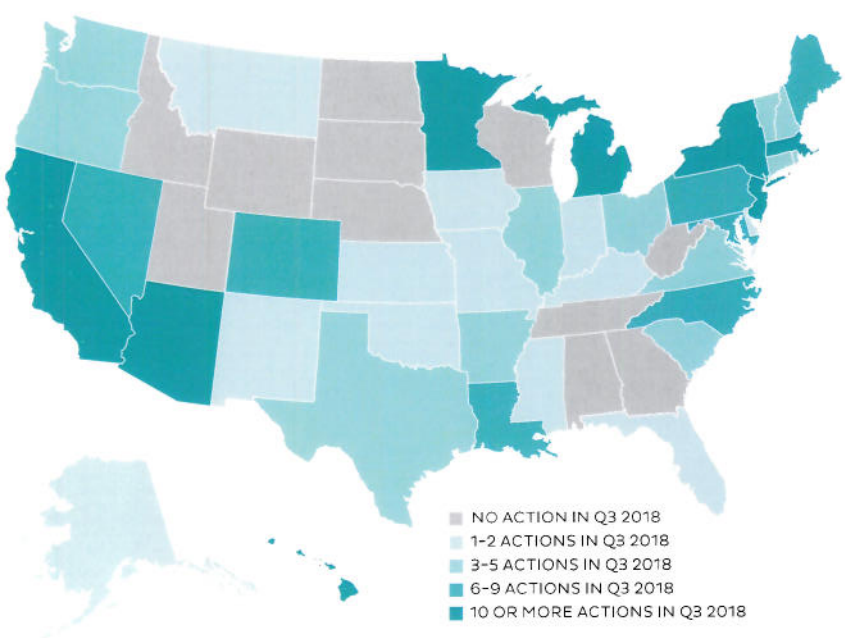
4A. STATE REGULATOR EFFORTS TO SEIZE POTENTIAL & MITIGATE CHALLENGES

Many state utility regulators are conducting proceedings related to grid modernization. Most of these proceedings are litigated, initiated in response to specific IOU's grid investment proposals. In some of these cases (IN, MO, and VA), IOU proposals were prompted by legislation offering IOUs additional economic incentives (generally, enhanced cost recovery) for grid modernization. Some state regulators have initiated state-wide investigational proceedings on their own initiatives. Investigational proceedings are generally prompted by one or more reasons, either 1) a perceived need to bring order and standardization to multiple IOU proposals or expressed intentions (IL and OH); or 2) a specific interest in preparing the grid for high levels of DER (CA, DC, HI, MA, MD, NY, and RI); or 3) a specific interest in developing a standardized grid planning process (MN and NV, but also CA, NY, and OH).

In general, state regulators are recognizing that the application of traditional rate case processes leaves much to be desired when it comes to grid modernization. While state regulators always maintain the right to deny cost recovery for investments deemed imprudent, this right is difficult to assert in grid modernization for two reasons. First, grid modernization proposals are generally so large that cost recovery denial will harm a utility's financial standing. Regulators in most states strive to preserve IOU financial standing out of customer interest, though in a few states this is a legislated regulator duty. Second, while imprudence is difficult to prove in almost any circumstance, it is particularly difficult to prove in grid modernization. As mentioned earlier, the benefits of grid modernization vary widely from utility to utility, meaning that the definition of "used and useful" incorporates a continuum. While a given grid investment may not have delivered direct economic benefits to customers sufficient to make that investment cost-effective (i.e., a favorable benefit-to-cost ratio), it is almost impossible for any grid investment to be deemed completely worthless or imprudent (i.e., not at all used and useful).

FIGURE 4. *Q3 2018 Legislative and Regulatory Action on Grid Modernization*

Source: "50 States of Grid Modernization". NC Clean Energy Technology Center.



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Regulators are thus taking several approaches to remedy the shortcomings of traditional rate case prudence review relative to grid modernization. In Colorado and Kentucky, regulators have deemed extra-ordinary grid investments, or those "not needed in the routine course of business", to require a Certificate of Public Convenience and Necessity (CPCN), as would a new generating plant. This requires utilities to submit grid investment plans and justification in advance for stakeholder review and challenge. Forward test years also require such plans and justifications. But in most states, grid modernization proceedings are simply responses to specific utility applications. Utilities attempting to mitigate the risk of cost recovery denials are voluntarily submitting plans and justification for large grid investments in advance. Despite no requirement (CPCN, forward test year, or otherwise) to do so, IOUs are keen to secure a level of comfort from their regulators that cost recovery denial is unlikely before making a large investment in grid modernization.

Regulators who initiate investigative proceedings on their own initiative are not intending to develop regulations, but to identify issues. They make extensive use of working groups to get stakeholders talking rather than litigating. Regulators task working groups with documenting principles and strategies on which stakeholders can agree, and with identifying important issues on which stakeholders cannot agree. Some regulators ask working groups to establish plans to resolve disagreements. Most regulators establish separate working groups for specific grid modernization issues, like "Consumer Technologies" (DER and electric vehicles), "Utility Technologies" (smart meters or distribution automation), "Utility Compensation and Business Models", or "Distribution Planning". These investigative proceedings have resolved few controversies to date, and all are still open. But given the early stage of grid modernization in South Carolina, a focus on emerging best practices in distribution planning offers particularly valuable insights for stakeholders, and so is the subject of the next section.

4B. BEST PRACTICE PRINCIPLES & STRATEGIES FOR INTEGRATED DISTRIBUTION PLANNING

Integrated Distribution Planning (IDP) is emerging as a best practice for providing a transparent framework for planning the distribution system. Several states (CA, MN, NV) have adopted IDP, and several others are considering adoption. GridLab's recently authored paper, Integrated Distribution Planning: A Path Forward, outlines recommended principles and strategies for integrated distribution planning.[24]

Recommended Principles for Integrated Distribution Planning

Ongoing. No utility's distribution grid will ever be finished unless technological advances render the distribution grid obsolete. Until then, decisions will need to be made about how much to invest, the capabilities in which to invest, and the extent to which capabilities should be expanded throughout a grid's circuits (geography). A standardized, repeating IDP process should be the norm for all utilities' distribution grids going forward, much like integrated resource planning has become the standardized, repeatable process for generation.

Integrated. The grid exists to distribute electricity from the transmission grid and generating sources. IDP processes must therefore consider, and contribute to, transmission plans and integrated resource plans. From distributed generation forecasts to demand response programs, IDP processes must be integrated with other electric system component and capability plans.

Transparent. Stakeholders, as representatives of those paying for grid modernization, should have a strong role in IDP processes. Stakeholders should help determine the criteria and weighting used to evaluate proposed grid projects, the opportunity to review and question utility evaluation results, and the opportunity to provide input in IDP regulatory proceedings. Stakeholders should have the educational opportunities and/or resources to gain and/or hire independent expertise on technical issues, much like they do for integrated resource planning today.

Objective. No grid project, suite of grid projects, or group of stakeholders should be advantaged over others in an IDP process. Every proposed grid project should be evaluated and prioritized using the same criteria (safety, reliability, storm recovery, DER accommodation, conservation, costs, or others) and weighting as every other proposed grid project, as agreed upon by stakeholders in advance. There are few justifications for considering projects outside a defined IDP process, as the grid should be planned to deliver certain goals at the lowest cost. (Exceptions may include a few "foundational" grid modernization capabilities, described below, and non-discretionary projects, such as accommodating large commercial developments, or road or mass transit construction).

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The overall goal of an IDP should be to deliver large benefits relative to costs, and transparency and objectivity should be employed to deliver it. While many stakeholders get hung up on nomenclature and classifications (What is grid modernization vs. business as usual investment?), it is possible such distinctions are somewhat counter-productive. GridLab believes that stakeholders are best served by having all grid investments – from reconductoring to smart meters to distribution automation – considered as part of a single IDP process. GridLab has found that such distinctions have proven meaningless in any event, as a capability one utility considers business as usual is considered by another utility as a policy/process/standard improvement, and by yet another utility as grid modernization. IOUs may be interested in preferred compensation for grid modernization, which leads to IOU interest in categorization. GridLab believes preferred compensation leads to excess investment, and recommends instead that preferred compensation be dedicated to exceptional performance on measured outcomes (see next). To summarize, it seems reasonable to separate preferred compensation from IDP process design and execution.

Measurable. Stakeholders have the right to expect objective (not subjective), measurable impacts from most grid projects. The same criteria used to justify a project (reliability improvements in SAIDI minutes per year, or MW increases in DER capacity, as examples) should also be used to measure the outcomes of projects selected for implementation. IDP processes should therefore incorporate both benefit forecasts and benefit measurement.

Consequential. Utilities should agree to comply with the outcomes of IDP processes, and to deliver the results promised from selected grid projects. Consequences should be associated with failure to comply with IDP process outcomes, or failure to deliver results. This principle involves nothing more than an equitable allocation of risk. In the absence of IDP, benefits measurement, and consequences, shareholders bear no risk (cost recovery is virtually assured), while customers bear 100% of grid project performance risk.

Customers also bear technology obsolescence risk. Consider an IOU which installs a multi-million dollar software package or communications network. Without independent technical oversight or stakeholder engagement, an IOU can simply change its business practices or operating processes to justify wholesale replacement of technologies installed just a few years ago. In such a manner an IOU can engage in a never-ending cycle of "upgrades" which maintain and grow the asset base on which the IOU earns a profit with no consequences. Again, a sustained IDP process can help address capital bias and associated business process, operating practice, and technology changes and choices of dubious value.

Recommended Strategies for Integrated Distribution Planning

Risk-informed Project Prioritization and Selection Decision Support. This is perhaps the single most important IDP strategy. Utilities have had access to risk-informed project prioritization and selection decision support software for decades. Unregulated businesses use this software when capital is constrained to make difficult choices from among competing projects. While unregulated businesses have a built-in incentive to minimize capital spending per unit of sales, regulated IOUs do not have this capital control mechanism. The software allows users to establish evaluation criteria, assign weights to criteria, and to rate each project's ability to deliver various criteria outcomes. The software then calculates a benefit-cost ratio for each project, ranking them from best to worst on a list of proposed projects. Employed in an electric utility context, stakeholders can use the list to help decide where to "draw the line", making informed choices about which projects get funded, and which are left for consideration in the next IDP cycle. Risk-informed project prioritization and selection decision support can help IOUs invest more like unregulated businesses subjected to competitive forces.

Circuit-specific Load Forecasting. One of the inputs to the IDP should be circuit-specific load forecasts, to include new loads such as electric vehicles or commercial or residential property development. Such forecasts help identify circuits in need of capacity upgrades, beneficial grid reconfigurations (to better balance loads among circuits and substations), and opportunities for non-wires alternatives (see below).

Circuit-specific DER Hosting Capacity Analysis. Another important IDP input is circuit-specific DER hosting capacity analysis. Hosting capacity analyses take circuit conditions (such as impedance), capacity, loads, load forecasts, and other information into account to determine the DER hosting capacity (in MW) of a circuit. Hosting capacity analyses can help identify which circuits might require increases in grid configuration flexibility made necessary by high DER capacity relative to loads. Hosting capacity results can also be used to help streamline interconnection application review processes for smaller DER (such as inverter-based rooftop solar or storage) by identifying circuits in no danger of approaching hosting capacity limits.

Locational Benefits Analysis/Non-Wires Alternatives. Some IDP processes are being designed to take advantage of locational benefit analyses. A derivative of circuit-specific load forecasting, locational benefits analyses identify opportunities to delay or avoid grid investments which might otherwise be needed by reducing a circuit or substation's peak demand. Circuit-specific demand response and electric storage are two examples of "non-wires alternatives" which could be used to reduce peak demand of a circuit or substation, deferring or avoiding utility investments. Some IDP processes are being designed so that customer or third-party bids for non-wires alternatives could be considered as options to utility grid investment.

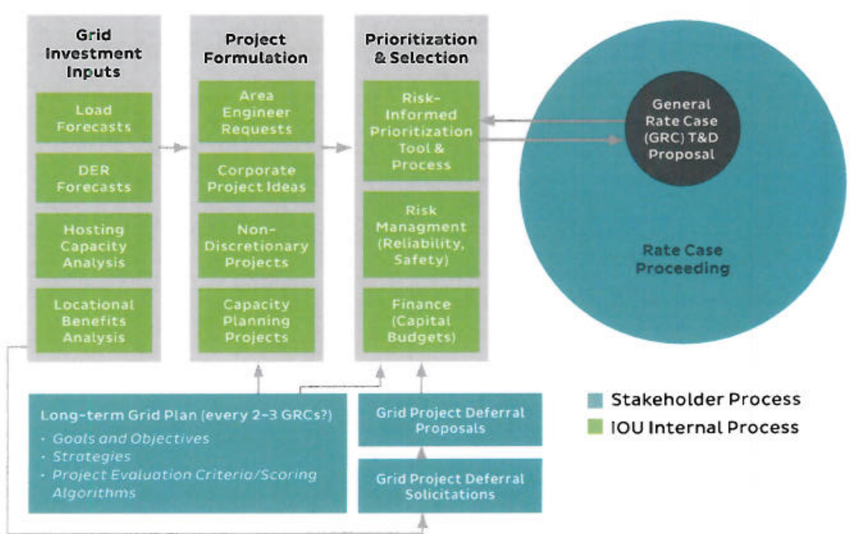
Distinguishing Between "Foundational" and "Geographic" Grid Investments. The biggest dollars in grid modernization lie in physical upgrades to grid equipment — bigger conductors; new ties between circuits; remotely-controlled switches, capacitor banks, and voltage regulators; line sensors to observe and report grid operating conditions in near-real time; communications networks; etc. These are considered geographic grid investments, in which foundational grid capabilities are extended out to the grid as needed for reliability improvements, DER accommodation, conservation voltage reduction, and other criteria established by stakeholders as part of the IDP process. The "need" to extend capabilities to certain circuits should be determined by the risk-informed project prioritization and selection decision support software, with the help of load forecasts and DER hosting capacity and locational benefits analyses.

Foundational grid investments are different than geographic grid investments, and more difficult to evaluate via risk-informed project prioritization and selection software. Foundational grid modernization investments are likely to consist of grid control center software, and are designed to help grid operators make better choices when re-configuring the grid in response to service outages and variation in DER output. The best examples are grid operations and modeling tools like Advanced Distribution Management Systems (ADMS), DER Management Systems (DERMS), and Integrated Volt-VAR Control (IVVC). Obviously, these capabilities must be established in the control center before they can be physically extended to various grid circuits on an as needed basis. For this reason, there may be justification to consider foundational investments outside the standard IDP process. Some regulators have considered smart meters as foundational investments, though this should not stop stakeholders from attempting to maximize and measure the direct economic benefits to customers from smart meters, or from comparing smart meters to other available grid investment choices on a benefit-cost basis.

Timing and Frequency. Like integrated resource planning, IDP processes are resource-intensive for utilities, regulators, and stakeholders. As a result, IDP processes should be conducted somewhat infrequently, though not so infrequently as to miss trends in load growth and DER growth. Most IDP processes in development appear to be designed for three to five year planning cycles, with shorter cycles more appropriate for more dynamic electric markets. Some regulators appear to be tying IDP cycles to rate case cycles, especially in states employing forward test years, as might be expected.

Combining Recommended Strategies into an IDP Process. The diagram below describes how the IDP strategies described above can be combined into a cyclical IDP process.

FIGURE 5. *Gridlab Proposed Distribution Planning Process*



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5 DUKE ENERGY'S GRID IMPROVEMENT PLAN: SUGGESTED INQUIRIES

GridLab has reviewed the Grid Improvement Plan materials Duke Energy submitted to the South Carolina Public Service Commission, and observed some admirable characteristics, some significant challenges, and some critical plan omissions. After an overview of Duke Energy's Plan, this section discusses these observations in some detail.

5A. OVERVIEW OF DUKE ENERGY'S PLAN

The South Carolina Grid Improvement Plan (Plan) proposed by Duke Energy Progress and Duke Energy Carolinas includes $454.5 million in capital spending over three years. This spending is organized into 18 different programs. Most of the programs are designed

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to improve reliability (fewer and/or shorter service outages) and speed service restoration after major storms. Also referenced in Plan materials are two other programs for which investment is undoubtedly significant, but for which no details are provided. These include "business as usual" grid investments (which Duke Energy refers to as "Maintaining the Base") and an Advanced Metering System investment. The reason these investments are not included in the Grid Improvement Plan and capital spending totals is not explained.

Only six of the 18 described programs, representing capital investments of $198.5 million, are considered by GridLab to be modern grid technologies. "Modern" grid technologies are those that employ software to analyze data from multiple locations on grid conditions in near-real time to help grid operators make (and in some cases execute without human input) grid operating choices (from voltage settings to grid configuration) and optimize capacity upgrade decisions. This does not make the other, more traditional technology programs bad, necessarily, though it does provide a reasonable rationale for focus on some programs over others in this overview. Descriptions and discussions of the six modern grid technologies are provided below.

Self-Optimizing Grid (SOG, $96.5 million)

Unbeknown to most customers, utilities reconfigure their distribution grids on occasion. Reconfiguration consists of switching the source of power for a circuit or subsection from one substation or circuit (the primary source) to another (the secondary source). The most common reason for reconfiguration is a service outage, during which power can be temporarily supplied from a secondary source while the problem with the primary source is repaired. This is done to reduce the number of customers impacted by an outage, though customers in the immediate area of the problem (an isolated subsection) still need to wait for repairs to be completed before their service is restored. Temporary reconfigurations can also be required when some circuits or subsections are undergoing maintenance or upgrades (to minimize the number of customers impacted by "planned" outages).

Today, the planning and execution of grid reconfigurations is handled manually. Grid operators must devise a plan as to how power is best re-routed, considering available secondary sources, their capacities, likely circuit loads, etc. The goal is to not make a reconfiguration mistake which might cause larger outages or damage equipment. Once the plan is established, it is executed manually, by sending out linemen in trucks to throw various switches and make other equipment adjustments as required, thus altering the "steady state" grid configuration.

What Duke Energy refers to the self-optimizing grid as is called "Fault Location, Isolation and Service Restoration" in most grid modernization plans. It consists of three components: 1) Increasing the number of reconfiguration options available (by building more ties between circuits, expanding the capacity of circuit subsections likely to be used as secondary sources, and establishing more circuit subsections); 2) Installing equipment which enables remotely-controlled operations (rather than having to send out linemen); and 3) Providing analytical and grid modeling tools (like Advanced Distribution Management Systems) to improve reconfiguration modeling and planning (and reduce the likelihood of mistakes). This last item is particularly important for circuits with high levels of DER, as high levels of DER complicate reconfiguration planning.

With SOG, Duke Energy will be able to reconfigure its circuits more easily, more frequently, and with less likelihood of an error. Note that while SOG as a whole is innovative, most of the spending is on traditional technologies like circuit tie construction and circuit section capacity expansion. Questions stakeholders might want to ask regarding SOG are listed in Section 5C.

Integrated Volt-VAR Optimization (IVVC, $45.6 million)

Like reconfiguration, the management of voltage and power factor (VAR) is a routine utility activity. Utilities monitor voltage and power factor, and change settings on equipment (load tap changers, voltage regulators, and capacitor banks) to maintain voltage and power factor within acceptable tolerances. Like reconfiguration, the processes utilities use to monitor voltage and power factor status, and modify equipment settings, are highly manual and infrequently employed. Most changes are only considered and implemented in response to customer complaints (when lights flicker, personal computers reboot, sensitive industrial processes are impacted, etc.)

Like SOG, IVVC involves facilitating voltage and power factor management by improving operational capabilities. In the case of IVVC, improved capabilities include monitoring voltage and power factor data continuously; installing equipment which enables remotely-controlled operations; and through automation (software which continuously analyzes data and remotely executes changes to equipment settings).

With IVVC, Duke Energy will be able to optimize voltage and power factor continuously, in real time, as long as the system (data collection, analysis, and equipment) is engaged. Through this capability, IVVC can be employed to reduce average circuit voltage, which in turn reduces the energy some types of customer equipment uses (called resistive loads). Reducing voltage to conserve energy is called Conservation Voltage Reduction, and represents one of the best customer-oriented investments a utility can make (as it reduces customer bills through no effort on customers' parts). However, IVVC can also be used for other purposes; by using IVVC to raise voltages, a utility can increase customers' energy use, and cause inverter-based DER like PV solar to drop offline (interrupting DER electricity production). Questions stakeholders might want to ask regarding IVVC are provided in Section 5C.

Energy Storage ($24.5 million)

While energy storage offers several potential benefits to an individual customer considering a purchase, the focus here is on potential benefits to the distribution grid/entire customer base. And while energy storage can take many forms, we focus here on the form in Duke Energy's Plan: batteries.

Batteries on the distribution grid can serve several potential functions, but the value of each is in dispute. Batteries can moderate electric frequency variation and provide voltage support, though these are not significant issues on most utility systems. Batteries can defer grid capacity upgrades, though they are currently an expensive way to do so. Batteries can provide back-up power in the event of an outage, though again at great cost and only for a few hours.

Energy storage is still quite expensive per MW of capacity and per MWh of back-up, so comparative benefit-cost analyses against available alternative approaches to solve the issue at hand are highly advised. However, battery prices and capabilities are improving rapidly, meaning it probably makes sense for utilities to gain experience with energy storage through pilot projects.

Transmission System Intelligence ($21.8 million)

Like SOG and IVVC, Duke Energy's Transmission System Intelligence project involves improving the Utility's ability to monitor grid conditions and equipment, and to operate that equipment remotely without having to send a lineman. The specific target is substation equipment and operations, where failures impact very large numbers of customers. The goal is to proactively identify anomalies in grid conditions and substation equipment that presage outages, enabling greater proactivity on the part of Duke Energy and improving reliability.

Integrated Systems Operations Planning ($6.3 million)

Operations planning software helps utilities optimize grid investment and construction plans over the long term. Such software uses mathematical models to mimic a utility's grid in digital form, allowing utilities to run "what if" scenarios. Various situations (i.e., what

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if a fault occurs at this location on this circuit?) can be simulated in multiple scenarios, covering everything from load growth to DER capacity growth, in order to estimate grid impacts. By estimating grid impacts in advance, utilities can better plan reconfiguration strategies in response to events, and design grid capacity increases intended to avoid, or reduce the geographic extent of, service outages.

DER Dispatch Tool ($3.8 million)

DER dispatch tools are considered a subset of a broader category of DER management software called DERMS (Distributed Energy Resource Management Systems). While DERMS can help utilities better manage DER generation, including high volumes of smaller DER like rooftop solar, DER dispatch tools are specifically targeted to large grid-located (vs. customer-located) DER, like multi-MW PV solar fields covering several acres, or large battery installations at a utility substation. With DER dispatch, Duke Energy will be better able to monitor the availability and status of large DER, control them as needed (such as in a service outage or planned grid reconfiguration), and model their outputs under various weather and grid conditions.

5B. POSITIVE PLAN CHARACTERISTICS

There are several admirable characteristics of Duke Energy's Grid Improvement Plan. Admirable characteristics, along with associated improvement opportunities, are described below.

The Plan Correctly Identifies Approaching Megatrends

Duke Energy is to be commended for identifying approaching megatrends for which its South Carolina grid might need to be prepared. Duke Energy correctly notes increases in grid security threats, DER capacity, electric vehicles, customer interest in emissions reductions, storm frequency and severity, and customer service expectations. Duke Energy also identifies potential impacts of these trends for South Carolina customers if left unaddressed. However, no megatrend data specific to South Carolina is provided, casting doubt about impact sizes and immediacy (neither of which is quantified or estimated).

The Plan Describes Proposed Solutions

Duke Energy's Plan describes capital-intensive solutions it proposes to address the megatrends and avoid negative impacts of unknown size and timing. However, Duke Energy provides no information on alternative solutions it may have or should have considered, leaving stakeholders to question whether more cost-effective solutions to the identified megatrends might be available.

The Plan Recognizes the Value of Cost/Benefit/Risk Analyses

Duke Energy is to be commended for applying an analytical approach to grid improvement investments. Duke Energy even provides its project justification protocol, which offers both subjective and objective paths to project selection and implementation. However, it appears the objective cost/benefit/risk analyses Duke Energy completed suffer from several deficiencies (see examples in Sections 5C and 5D below). Objective cost/benefit/risk analyses are not provided for several proposed projects, including one of the largest (smart meters, see below); criteria for subjective evaluation are few; and evaluations of projects selected through subjective justifications, as well as evaluations of alternatives to proposals not selected (protocol Step 3b), are not provided.

Duke Energy Attempted to Engage Stakeholders

Duke Energy's attempt to engage stakeholders is a reasonable first step, and represents an improvement over its engagement in other states. However, the workshops appear to have been designed to promote Duke Energy's Grid Improvement Plan, the stakeholders were at a significant technical disadvantage, and stakeholder engagement to date includes none of the IDP principles and strategies presented in Section 4B.

5C. PLAN CHALLENGES

While there are things to admire about the Duke Energy Grid Improvement Plan, there are many significant shortcomings. These relate mostly to the benefit-to-cost analyses for proposed programs, including missing South Carolina data, a lack of operating targets on which benefit estimates are based, missing benefit-to-cost analyses for most proposed programs, and a dearth of alternatives to Plan projects as well as associated evaluations of those alternatives.

Megatrend Data and Anecdotes Specific to South Carolina Are Not Provided

While Duke Energy correctly identified approaching megatrends, all megatrend data and anecdotes were global. Duke Energy provided no evidence to quantify

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the degree to which megatrends are impacting, or expected to impact, South Carolina, nor the speed with which such trends are advancing in South Carolina. This information is critical to prioritizing grid improvement spending and ensuring such spending is the minimum amount required to address South Carolina's situation specifically. Recommended lines of inquiry are listed below.

Physical Grid Security. How many physical attacks has Duke Energy's infrastructure, in South Carolina or elsewhere, actually suffered? Were any outages caused? What was the cost of the damage incurred? What was the nature (method) of the attacks? By how much do the proposed physical improvements reduce the likelihood of attacks of this nature, or of attacks in general?

Cyber Grid Security. Have any US utilities — including municipal and co-operative utilities with much less sophisticated cybersecurity than Duke Energy — been successfully cyber-attacked? What was the nature (method) of such attacks? By how much do the proposed cybersecurity improvements reduce the likelihood of attacks of this nature, or of cyber-attacks in general?

Reliability. What is the five-year average SAIDI, SAIFI, and MAIFI history for South Carolina circuits? Are certain circuits driving the reliability deterioration? Are certain causes or conditions responsible for a disproportionate number of outages? How do the proposed projects address these causes or conditions? How do SAIDI, SAIFI, and MAIFI trends and performance in Duke Energy's South Carolina service area compare with those of the average US IOU? How do these compare with IOUs in North Carolina, South Carolina, and Georgia?

Storm Restoration. What was the total restoration time of hurricane Michael? Of hurricane Florence? What were the critical dependencies (substations, circuits, laterals, etc.) driving the total restoration times experienced in each? How were these critical dependencies similar and different for each storm? How often have the substations chosen for flood upgrades been flooded in the past? How do the proposed investments manage the most commonly-encountered critical dependencies, and how were they prioritized across Duke Energy's South Carolina service area? What total restoration time improvement would the proposed investments have delivered had they been in place for Michael and Florence, and for how many customers?

DER Capacity. What is DER capacity relative to Duke Energy's South Carolina grid capacity? What is the highest DER capacity on a single South Carolina circuit? How do these figures compare to other utilities with significant grid improvement initiatives, such as California and Hawaii? What issues has DER caused for Duke Energy in South Carolina to date? What does the South Carolina DER capacity forecast look like in terms of size and timing?

Electric Vehicles. How many electric vehicles does Duke Energy estimate are in its South Carolina service area? What does the South Carolina electric vehicle forecast look like in terms of size and timing? What increase in electric demand will this create in managed and un-managed scenarios? How big are these increase in demand relative to grid capacity? How does Duke Energy expect this demand increase to be spread among its South Carolina Circuits?

Customer Expectations/Market Research. What are the attitudes of South Carolina customers regarding climate change? Regarding reliability? Customer service? Energy management? How are these attitudes changing over time? What does "willingness to pay" research Duke Energy has conducted in South Carolina say regarding customer impressions of utility spending on emissions reductions, reliability, customer service, and energy management?

Critical Operating Targets Are Not Provided

The cost-benefit analyses Duke Energy provided are missing critical operating targets on which economic benefit estimates were based. Without these operating targets, it will be impossible for South Carolina stakeholders to determine if the Plan delivered the economic benefits Duke Energy forecasted. Recommended lines of inquiry are listed below.

Integrated Volt-VAR Control (IVVC) Program. Though IVVC conservation voltage reduction can be highly beneficial for customers, utilities control the size of the benefit, and the bigger the benefit, the bigger the utility earnings reduction (per the throughput incentive described in Section 3B.). As a result, significant IVVC inquiries and oversight are warranted. What MWh reductions are required on treated circuits to deliver the economic benefits Duke Energy estimates in its cost-benefit analysis? What reductions in average annual voltage on these circuits does Duke Energy estimate will be required to deliver the estimated MWh reductions? What is the average annual voltage on these circuits today? What percentage of annual circuit operating

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hours (8,760) will Duke Energy need to operate IVVC for conservation voltage reduction to achieve targeted MWh and average voltage reductions? What actions can Duke Energy take to increase the percentage of time IVVC is employed for conservation voltage reduction, thereby increasing the benefit-to-cost ratio for South Carolina Customers? Should IVVC be installed on more circuits? Which ones?

Self-Optimizing Grid and Transformer Retrofit Programs. Though utilities are not economically penalized for maximizing reliability-related benefits in the way that they are by conservation, there are still decisions stakeholders can influence to improve the benefit-cost ratio. How were circuits selected for reliability investments? What are the customer characteristics (density, presence of sensitive facilities like first responder and nursing home facilities, etc.) of these circuits? What are the average historical SAIDI and SAIFI statistics for these circuits? What specific improvements in SAIDI and SAIFI, in minutes and interruptions, are required on these circuits to deliver the economic benefits Duke Energy estimates in its cost-benefit analyses? How did Duke Energy translate SAIDI, SAIFI, and MAIFI improvements into economic benefits? Did Duke Energy use the US Department of Energy's online Interruption Cost Estimate Calculator? How do circuit-specific improvements translate into overall SAIDI, SAIFI, and MAIFI improvements in South Carolina? How will the new performance levels compare to the average US IOU? How do these new performance levels compare to the average IOU in North Carolina, South Carolina, and Georgia? How will Duke Energy manage the safety risks associated with the Self-Optimizing Grid (energized downed lines risk)?

Cost-Benefit Analyses Were Not Made Available for the Majority of Programs

Duke Energy only made summary cost-benefit analyses available for three programs (IVVC, Self-Optimizing Grid, and Distribution Transformer Retrofit) totaling $165.1 million in investment. As described immediately above, critical details were missing from the three summary analyses provided, which reduces the analytical value of these analyses to stakeholders almost entirely. But just as critically, cost-benefit analyses and associated operating details for 15 other programs totaling $289.5 million in investment were not provided at all. Cost-benefit analyses (but no details) were provided on just three example projects in two Plan programs, though examples cannot be used to justify an entire program. In fact, Duke Energy's Plan includes no estimate at all of the total economic benefits, direct or indirect, customers can expect from the execution of its Plan.

With just two exceptions (see next), GridLab recommends that cost-benefit analyses and operating details be provided on all proposed programs. This includes a cost-benefit analysis of the smart meter program, for which Duke Energy will request cost recovery but which is not discussed at all in Duke Energy's Grid Improvement Plan. At an estimated cost of $225 to $300 million for 740,000 meters, this critical omission is discussed in Section 5D below.

Alternatives Available for $96 Million in Investments Do Not Appear to Be Considered

Cost-benefit analyses are admittedly not the best evaluation approach for some of the investments in Duke Energy's Plan. The physical and cyber security investments totaling $55 million, as well as communications network investments totaling $41 million, fall into this category. However, in the place of cost-benefit analyses, Duke Energy should make available to stakeholders the evaluations of alternatives to these investments it considered, or should have considered.

Physical and Cyber Security Investment Alternatives. Duke Energy's Plan includes $55 million in capital for grid security improvements, including over $36 million for substation physical security. While Duke Energy categorizes these improvements as "required for compliance", no details are provided as to the specific NERC or CIP guidelines with which Duke Energy is attempting to comply. No details are provided on what the physical substation security improvements are, nor on the types of physical threats the improvements are designed to thwart, nor on the likelihood of such threats. Evaluations of various alternatives to this $36 million investment, including no investments at all, are warranted.

Communications Network Investment Alternatives. Duke Energy's Plan includes $41 million in communications network upgrades, 80% of which appear to be related to grid data transport. Notably, the Plan makes no mention whatsoever about the communications network Duke Energy is installing to read its advanced meters. This is a time of rapid change in wireless communications technologies. New low cost, low power, wide area networks are now available from Verizon

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(Cat M1) and AT&T (NB-IOT). These networks were designed specifically for the Internet of Things era and "machine to machine" (fixed in place) communications needs. Smart SIM cards are now available which can be remotely reconfigured to work with a variety of network technologies, facilitating an easy transition from 4G cellular to 5G cellular, for example. The Rhode Island PUC has specifically asked Narragansett Electric to resubmit its grid modernization plan with a variety of communications options for consideration.[25] Before Duke Energy invests $36 million in its grid communications network, and likely tens of millions more in its meter communications network, evaluations of available communications options are clearly called for.

Duke's Grid Improvement Plan Is Dominated by Traditional Technologies

Only a third of the eighteen programs in the Plan, comprising less than half of the proposed investment, could be characterized as modern grid technologies (see Section 5A.). The majority of the Plan consists simply of expansions of traditional technologies. What Duke Energy calls "Distribution Automation" involves the installation and upgrade of reclosers, a technology available for decades; likewise, Static VAR Compensators (power electronics for Volt-VAR Control) have been in common use for decades. Outfitting distribution transformers with fuses, upgrading substation transformer banks, and providing back-up power sources to remote locations are all things utilities have done for decades. This does not make these components bad ideas, but it does call into question the rationale for premium cost recovery.

The focus on traditional technologies can have some potential shortcomings, however. In GridLab's experience, undergrounding of overhead lines ($27.5 million in Duke Energy's Plan) has one of the worst benefit-to-cost ratios of any investment intended to improve reliability. High voltage circuit breakers filled with SF-6 gas have been around for a long time, but SF-6 is an extremely powerful greenhouse gas. It traps heat in the atmosphere at a rate 23,900 times more powerful than carbon dioxide.[26] How much more effective are gas circuit breakers than traditional oil-filled circuit breakers? Have the environmental costs of SF-6 circuit breaker installation, operation, and decommissioning been taken into account? Furthermore, the Plan includes no details on how new grid capabilities (traditional or modern) will be used to accommodate increases in DER capacity, a decidedly modern development.

5D. CRITICAL OMISSIONS

While Duke Energy's planning process and Plan exhibit multiple and significant improvement opportunities, some omissions are deemed wholly unacceptable.

The Plan Includes No Performance Improvement Commitments

While Duke Energy claims their proposed programs feature a favorable benefit-to-cost ratio, it makes no commitments to achieving the operational targets required to deliver the economic benefits estimated. If Duke Energy customers are paying for grid improvements, they have the right to know how much reliability improvement — in SAIDI minutes and SAIFI and MAIFI interruptions — they can expect. Customers have a right to know how much Conservation Voltage Reduction — in MWh — they will earn. Customers have a right to know how much — in percent — total restoration time after a major storm will improve. Customers have a right to know how much DER capacity — in MW — the South Carolina grid can accommodate today, and how much more DER capacity the investments will accommodate if made. GridLab recommends all these performance measures, with economic consequences for failure to achieve them, as the Illinois legislature has employed with IOU smart meter Plans in that state.[27] Without such commitments and consequences, 100% of the risk of Duke Energy performance falls on customers.

The Ultimate Cost of the Plan to Customers Is Understated by At Least 50%

Duke Energy appears to estimate costs based on the capital it will spend to implement the Plan. However, customers pay more than capital costs. On top of capital costs, customers must pay Duke Energy profits, corporate income taxes, and interest expenses, as well as South Carolina Gross Receipts taxes, local property taxes on assets, and South Carolina Regulatory Fees. These costs, called carrying charges, grow larger as the useful life of the assets grows longer. Most assets in the Plan are long-lived, and are expected to last 20-30 years. In GridLab's experience, carrying charges add anywhere from 50% to 100% to the ultimate cost to customers of long-lived assets (15-20 years or more). Other costs missing from Duke Energy's benefit-cost analyses include increases in asset operations and maintenance costs over time. GridLab recommends that customer benefit-to-cost ratios be re-calculated, with all costs customers will be asked to pay considered.

Cost Recovery Fails to Consider That Most Reliability Benefits Are Commercial

Duke Energy proposes rider cost recovery for its Plan, with relatively equal allocation among customer classes.[28] However, experience with the Interruption Cost Estimate Calculator, developed by Nexant and Lawrence Berkeley National Lab, indicates that about 98% of the economic benefits associated with reliability improvements accrue to commercial and industrial customers.[29] GridLab recommends cost allocations for investments intended primarily to improve reliability or storm restoration take into consideration the amount of economic benefits various customer classes will receive. Doing so is more equitable; will improve the residential customer benefit-to-cost ratio; and will motivate commercial and industrial customers to participate in IDP processes.

Plans to Maximize the Benefits of Smart Meters to Customers Are Wholly Absent

Finally, Duke Energy appears to have ignored smart meter costs, benefits, and benefit maximization plans entirely, which GridLab estimates to cost between $225 and $300 million. GridLab recommends a full smart meter plan be submitted for stakeholder review, including:

- A full customer cost-benefit analysis, to include full details and carrying charges;
- A benefit-cost-risk evaluation for multiple smart meter communications options, to include new low power, "Internet of things" networks available from telecommunication providers;
- A plan for default application of time-of-use rates, to include system peak reduction features such as peak-time rebate;
- A commitment to comply with the Connect-My-Data standard (as ordered in CA, CO, IL, NY, and TX);
- A plan to maximize the revenue assurance and operating expense reduction benefits from smart meters, along with a plan to recognize these benefits via customer rate reductions;
- A plan for how smart meter data will be integrated into grid planning, grid operations, voltage management, outage management, and other Duke Energy processes.
- A plan for how Duke Energy will write down — or recover from customers — the book value of meters removed from service to make way for smart meters.

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6 REVIEW AND CONCLUSIONS

This paper provides a guide as to how South Carolina can get a smarter grid for customers, and why doing so can deliver direct economic benefits to customers as well as indirect benefits to South Carolina communities and the environment. However, like most issues in the electric industry, and like most claims that seem too good to be true, the paper makes clear that the devil is in the details. The paper also makes clear that in order to secure grid modernization benefits in excess of costs, all parties to grid modernization — utilities, regulators, stakeholders, and customers — must commit to permanent increases in time, attention, and resources. To achieve a smarter grid at a low cost or no cost, resources must be dedicated to grid planning, project selection, and post-deployment project benefit maximization and measurement, as described throughout this paper. Getting a smarter grid at the least cost will require significant, ongoing efforts from all parties involved.

6A. BEST PRACTICES FOR INTEGRATED DISTRIBUTION PLANNING ARE EMERGING

Most states' utilities, regulators, and stakeholders are fiercely independent, believe their situations to be unique, and are keen to forge their own grid modernization path. There is no doubt that laws and rules vary by state, that goals vary by state, and that each utility's situation presents individual characteristics and variation in current circumstances which must be considered in grid modernization. However, the laws of physics, the principles of economics, and the challenges electric distribution grids and businesses are likely to face in the future, are the same everywhere.

As the body of grid modernization knowledge evolves, South Carolina legislators, regulators, and stakeholders are strongly encouraged to take advantage of experiences in other states. No matter the circumstance or challenge, some other state has probably already examined it and dealt with it in some way, with varying degrees of success. Learning about other states' experiences does not obligate South Carolina regulators and stakeholders to copy their solutions, but it can help avoid mistakes and extend successes.

6B. PERFORMANCE VARIATION AND UTILITY INCENTIVES MAKE OVERSIGHT MANDATORY

A sound grid modernization plan involves more than just technologies, capabilities, and investments. A sound grid modernization plan includes strong stakeholder engagement and regulatory oversight throughout the planning, implementation, and operational stages of grid development. To maximize return on investment for customers and the environment, integrated distribution planning processes must be designed to identify the most critical capabilities; the most cost-effective ways to implement them; the most appropriate geographic extent for them; and methods to maximize available benefits for customers, from conservation to performance measurement.

To recognize the importance of good governance is to appreciate the need for long-term oversight and ongoing participation in integrated distribution planning processes by regulators and stakeholders. Grid modernization is not solely the responsibility of utilities. Regulators and stakeholders must be prepared to contribute their own resources and take on new roles and responsibilities. Many of these new roles and responsibilities are the direct result of managing the conflict between shareholder and customer interests inherent in the current cost-of-service ratemaking model. At some point, the drawbacks of cost-of-service ratemaking may exceed its attributes.

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6C. IN THE LONG RUN, FUNDAMENTAL UTILITY COMPENSATION REFORM MAY BE NECESSARY

Capital bias, the throughput incentive, and cost recovery methods have driven utility investment and operating decisions for the better part of a century. Grid modernization governance requirements are driven largely by the need to manage the conflicts between shareholder and customer interests. Eliminating the conflicts eliminates some governance requirements (though not performance measurement, which is recommended in any event). As regulators and stakeholders have neither the technical expertise nor the resources required to rigorously evaluate utility's technical arguments for grid investments, a regulatory model which eliminates capital bias may be warranted. As customers become more interested in conservation and self-generation, the throughput incentive must also be addressed. As industry conditions change, utility compensation models likely need to change too.

This whitepaper presents many new issues neither the Commission nor stakeholders have previously considered. The issues are complex, the solutions are controversial, and the workload and negotiations required to address them will be formidable. Neither the Commission nor stakeholders are likely to have the technical experience required to effectively question IOU proposals and justifications for them. It may be tempting to minimize the issues, or to give up on grid modernization altogether, though either course of action short changes South Carolina businesses, consumers, and government and non-profit agencies. The potential benefits of grid modernization are large, and grid modernization is a worthy pursuit. But like all worthy pursuits, customers, communities, and stakeholders will get benefits out only if they put efforts in.

GridLab hopes readers have found this paper and its perspectives valuable. For more information or for questions, please contact Taylor McNair at GridLab: info@gridlab.org or 510-519-4208.

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ENDNOTES

1. "Distributed Energy Resources", or DER, are smaller power sources that can be aggregated to provide power necessary to meet regular demand. DER can include energy storage and advanced renewable generation technologies such as photovoltaic solar panels or waste heat/biogas-fueled turbines. DER can be owned by utilities, customers, or third-parties. Many people include demand response, in which customers reduce consumption when requested to improve system utilization, in the definition of DER.
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